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AVISTA Corp.

September 20, 2005

Mr. David H. Meyer
Acting Deputy Director
Office of Electricity Delivery and Energy Reliability
U.S. Department of Energy
Washington DC 20585

Dear Mr. Meyer:

Avista Utilities is pleased to submit its response to the Department of Energy and the WECC regarding economic dispatch by electric utilities and non-utility generators.

Section 1234 of the Energy Policy Act of 2005 requires the Department of Energy to conduct a study on the benefits of economic dispatch in the electric industry. The Department was directed to study the procedures used currently by the industry to perform economic dispatch, possible revisions to these provisions, and any potential benefits to electric consumers if economic dispatch procedures were revised.

The response prepared by Avista Utilities is attached. If you have any questions or comments, please email me at steve.silkworth@avistacorp.com or contact me by phone at (509) 495-8093. Thank you for the opportunity to provide comments on this issue.

Sincerely,

Steven G. Silkworth
Wholesale Power Manager
Avista Utilities

c:
via email
LeRoy Patterson, WECC
Scott Kinney, Avista Utilities
Dick Byers, WUTC
Randy Lobb, IPUC
Rick Sterling, IPUC

DOE Economic Dispatch Questions

Section 1234 of the Energy Policy Act defines economic dispatch as "the operation of generation facilities to produce energy at the lowest cost to reliably serve customers, recognizing any operational limits of generation and transmission facilities." With that definition in mind, please answer as many of the following questions as you wish, attaching supporting materials such as studies or testimony that was filed in state or federal regulatory proceedings to support your answer.

Questions

1) What are the procedures now used in your region for economic dispatch? Who is performing the dispatch (a utility, an ISO or RTO, or other) and over how large an area (geographic scope, MW load, MW generation resources, number of retail customers within the dispatch area)?

Avista Utilities serves approximately 300,000 electric customers in eastern Washington and northern Idaho with its hydroelectric, coal fired, natural gas fired, waste-wood fired facilities, power purchases and a wind power purchase. Avista owns approximately 1,400 MW of generation capacity. Avista's load represents approximately 5% of the Pacific Northwest's 30,000 MW load in the region.

In The Pacific Northwest, Each Generator Owner Economically Dispatches Their Generation Units In A Similar Manner, But In Accordance With Their Own Unique Set Of Circumstances.

Each generator owner in the Pacific Northwest, regardless of whether they may be a utility or non-utility entity, dispatches its own power generation units based upon supply obligations, the lowest variable economics of the generation units as compared to the market, and various non-power factors.

The Dispatch Sequence In The Pacific Northwest Region Is Different Due To The Presence Of Hydroelectric Generation.

The resource dispatch stack in the Pacific Northwest is significantly influenced by the substantial hydroelectric generation in the region. The characteristics of hydroelectric generation allow available water (fuel) to be shifted from one time frame to another within certain limits. Water inflow, storage capacity, project restrictions, environmental factors, as well as other limitations will determine the degree to which hydroelectric generation can be optimized across time.

Therefore in sequencing the dispatch stack, Avista first dispatches its lowest variable cost base-load thermal generation (coal) and its estimate for the production from wind resources. Recent market history has been such that coal-fired resource variable costs are always below market. Subsequently, the variable cost of each thermal resource, other than base load coal, is then compared to market and is scheduled to operate in accordance with its relative economics. Power from third-party suppliers is incorporated into Avista's dispatch sequence depending on the flexibility and terms given to Avista through the terms and conditions of the underlying contract. Avista next decides simultaneously on the amount of market purchases or sales that result as it optimizes the dispatch and shaping of its hydroelectric generation. In addition, Avista and the northwest region operate under two hydro coordination and optimization contracts called the Pacific Northwest Coordination Agreement (PNCA) and the Hourly Coordination Agreement. The PNCA allows for coordinated release of water throughout the water year among the many project owners on the Columbia River. The Hourly Coordination Agreement optimizes the realtime release of water among seven Columbia River power projects (from Grand Coulee Dam through Priest Rapids Dam) that provide load following for the majority of load within the Northwest.

Hydroelectric generation is also operated to provide regulation for moment-to-moment variations in load and resources including intermittent wind generation. In contrast to thermal generation units, hydroelectric generation generally has excess capacity available to provide regulation and reserve ancillary services at the lowest cost.

A special sub-set of the dispatch sequence described above would be long-term contract obligations tied to the operation of a specific generation unit, such as in the case of PURPA contracts, where a generator unit must run to satisfy contract obligations.

Other utilities and non-utility generators in the Pacific Northwest region can be expected to dispatch their units in generally the same manner but consistent with their own unique circumstances including physical location, lowest variable cost, fuel supply arrangements, transmission arrangements, contract or load obligations, and other non-power factors.

2) Is the Act's definition of economic dispatch (see above) appropriate? Over what geographic scale or area should economic dispatch be practiced? Besides cost and reliability, are there any other factors or considerations that should be considered in economic dispatch, and why?

The Act's definition is generally appropriate to describe "short-term" economic dispatch circumstances. However, the definition should include "non-power" or "other" factors, such as environmental restrictions, relating to dispatch. For example, the flexibility of hydroelectric and thermal power plant dispatch is often times limited by environmental restrictions. The Act's definition, however, does not appear to address long-term economic dispatch circumstances, which might include contract elements such as capacity or other fixed-cost type of payments. As described, the Act's definition, as well as responses to these questions, both pertain to "short-term" economic dispatch. The geographic scale of economic dispatch will generally be the area, which is not significantly transmission constrained on an hourly basis, within which counterparties measure their generation unit variable costs against a common market price.

3) How do economic dispatch procedures differ for different classes of generation, including utility-owned versus non-utility generation? Do actual operational practices differ from the formal procedures required under tariff or federal or state rules, or from the economic dispatch definition above? If there is a difference, please indicate what the difference is, how often this occurs, and its impacts upon non-utility generation and upon retail electricity users. If you have specific analyses or studies that document your position, please provide them.

Both Utility And Non-Utility Generators Compare Their Own Unit Variable Costs To The Same Non-Centralized Bi-Lateral Markets When Making Economic Dispatch Decisions In The Pacific Northwest.

In the Pacific Northwest region, economic dispatch procedures should generally be expected to be relatively similar between utility and non-utility generators. The results of their individual economic dispatch decisions may be somewhat different depending upon geographic location, specific variable costs components, fuel supply, occasional transmission constraints, load or contract service obligations and other factors such as environmental restrictions. Both utility generation units and non-utility generation units are looking at the same non-centralized bilateral markets to which they are comparing their variable cost to operate.

While states provide general oversight for economic dispatch as part of their responsibilities to ensure that retail customers pay the lowest reasonable cost for electric service, there are no federal or state tariff rules that would cause economic dispatch to occur differently from the discussion above under normal operating conditions.

State regulation of utility obligation to serve end-use customers requirements is intended to ensure that adequate resources are available to serve load obligations in the region.

4) What changes in economic dispatch procedures would lead to more non-utility generator dispatch? If you think that changes are needed to current economic dispatch procedures in your area to better enable economic dispatch participation by non-utility generators, please explain the changes you recommend.

Any changes to economic dispatch procedures should have nothing to do with specifically enabling "more non-utility generator dispatch," but should instead improve the overall ability to reliably dispatch the lowest cost generation resources, regardless of ownership status. The underlying intent of this question appears to suggest that non-utility generation projects are not able to economically dispatch their units. This question is misplaced, as it relates to the Pacific Northwest markets. As described in response to earlier questions, both utility and non-utility generation units have the opportunity to dispatch against active non-centralized bilateral markets in the Pacific Northwest region. The markets against which utility and non-utility generators dispatch are the same.

There are two issues that have been identified in the Pacific Northwest region that affect both utility and non-utility generation dispatch. These are: 1) The number of different OASIS sites that an entity may have to visit to arrange for transmission in the region; and 2) the existence of multiple transmission owners gives rise to the existence of multiple or "pancaked" transmission costs that may create transaction costs that are too great to enable a particular generation unit to economically reach a particular market. There is a caveat to the second issue, however, because it is also the case that the Bonneville Power Administration transmission system overlays the entire region with a system that represents approximately 70% of the high-voltage transmission grid in the region. Both utility and non-utility generators that can access the Bonneville transmission system are able to reach a large percentage of the market in the Pacific Northwest over one transmission wheel.

The two issues or circumstances described above can be mitigated, and improved economic dispatch can take place, through implementation of a single, region-wide OASIS and development of a coordinated, discounted pricing structure for non-firm transmission service applicable in the pre-scheduling time frame. The establishment of a single, region-wide OASIS that provides the transactional capability to access multiple systems with a single reservation request would enable lower-cost remote resources to access a given market without the added administrative burden of accessing multiple systems to establish needed transmission reservation(s). Furthermore, a coordinated discounting mechanism among multiple transmission systems for non-firm transmission service would enable lower-cost resources, in the absence of transmission congestion, to be dispatched to meet load. Such a discounting mechanism can be structured to create the effect of a single, common non-firm transmission rate applicable to all resources within a given market area. It should be understood, however, that the existence of multiple, or pancaked, *long-term* transmission rates do not hinder economic dispatch. The economic dispatch of resources is ultimately affected by the ability to reserve and schedule transmission service on pre-schedule and in real-time.

Additionally, it should be noted that a common, regional OASIS and discounting processes to mitigate the effect of multiple or pancaked transmission rates can be implemented either through a coordination contract structure or through the establishment of a regional transmission organization. The ability to mitigate inefficiencies associated with transmission reservations and transmission pricing for real-time dispatch are independent of the structural model in a given region.

5) If economic dispatch causes greater dispatch and use of non-utility generation, what effects might this have – on the grid, on the mix of energy and capacity available to retail customers, to energy prices and costs, to environmental emissions, or other impacts? How would this affect retail customers in particular states or nationwide? If you have specific analyses to support your position, please provide them to use.

Please see responses to both #4 above and #6 below.

6) Could there be any implications for grid reliability – positive or negative – from greater use of economic dispatch? If so, how should economic dispatch be modified or enhanced to protect reliability?

Economic dispatch practices are, and will continue to be, subject to applicable reliability criteria that are in place in the Pacific Northwest Region. Accordingly, economic dispatch protocols need not be modified, per se, since they are always subject to minimum operating reliability criteria.